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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION OF THE CONTINUED REASONABLENESS OF CURRENT SIZE LIMITATIONS FOR PURPA QF PUBLISHED RATE ELIGIBILITY (i.e., 1 MW) AND RESTRICTIONS ON CONTRACT LENGTH (i.e., 5 YEARS).	CASE NO. GNR-E-02-01

COURT REPORTER

REBUTTAL TESTIMONY AND EXHIBITS OF

DAVID HAWK

ON BEHALF OF

INDEPENDENT ENERGY PRODUCERS OF IDAHO

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Hawk. My business address is 999 Main Street, Suite 1000, Boise Idaho.

Q. WHAT IS YOUR OCCUPATION?

A. I am the Director, Energy Natural Resources for the J. R. Simplot Company. I am also the Chairman of the Board of Remington Oil and Gas Corporation headquartered in Dallas, Texas, a small cap oil and gas exploration and production company with a market value of approximately $500 million.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Independent Energy Producers of Idaho. However, since the J. R. Simplot Company is also a party to this case, my testimony may be viewed also as the position of the J. R. Simplot Company.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH THIS TESTIMONY?

A. Yes. I am sponsoring Exhibit Nos. 606 through 607.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS TO TESTIFY AS AN EXPERT IN THIS PROCEEDING.

A. As the Director, Energy Natural Resources of the J. R. Simplot Company, I am intimately familiar with almost all aspects of prospect generation, drilling, purchasing and transportation of natural gas. I routinely purchase natural gas for my employer's many diverse operations throughout the United States and Canada. In addition, prior to joining the J. R. Simplot Company in 1984, I previously held senior management positions in oil and gas exploration and production companies, Vice President and General Manager of a sister company of Intermountain Gas and as a manager in that utility. The J. R. Simplot Company, under my direction, was the first industrial customer to utilize open access transportation when it became available on Northwest Pipeline in June of 1985. We were the first, and for several years the only, industrial customer to receive a 7(c) certificate from the Federal Energy Regulatory Commission for such an access arrangement. The Company has played an integral role in the formulation and direction of energy policy affecting industrial energy customers at the FERC, numerous public utility and service commissions, and within industrial enduser organizations.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony is limited to the single issue of the appropriate initial gas price that is used to determine avoided cost rates.

Q. WHAT CONCLUSIONS DO YOU REACH FROM YOUR ANALYSIS OF THE VARIOUS PARTIES' TESTIMONY ON THE APPROPRIATE INITIAL GAS PRICE TO BE USED IN SETTING AVOIDED COST RATES?

A. On reviewing the positions of the various parties, it is apparent that there is a wide gulf between the high and low recommendations.

Q. PLEASE EXPLAIN?

The following table indicates the natural gas price recommendations by the various parties:

Avista	$2.75 per MMBtu
IPCo	$2.79 per MMBtu
Staff	$3.19 per MMBtu
IEPI	$3.91 per MMBtu
Pacific	$3.95 Per MMBtu

Q. DIDN'T THE IEPI RECOMMEND A LOWER GAS PRICE IN ITS DIRECT TESTIMONY?

A. No. The IEPI put forth two numbers, $3.84 per MMBtu and $3.91 per MMBtu. It is clear to me, after viewing the other parties gas cost estimates and current market conditions, that the Commission should use, at a minimum, the higher IEPI number, $3.91 per MMBtu or even Pacific's number, $3.95 per MMBtu.

Q. WHY IS THAT?

A. Today (August 2, 2002) I checked the price of gas at Sumas, which is the trading hub the Commission uses to set avoided cost gas rates, with IGI Resources, the preeminent gas marketing and supply agent for industrial customers in the Northwest. The price for one year's supply of firm gas, beginning November 1st was $3.36 per MMBtu.

Q. WHY DID YOU USE NOVEMBER 2002 TO OBTAIN A QUOTE ON THE SUMAS TRADING HUB?

A. November is considered the beginning of winter and the calendar point at which one year's supply is traditionally calculated. However, one can produce a one year strip price beginning with any month. Also, November 1st is my best estimate when the rates the Commission sets will become effective.

Q. ISN'T THE $3.36 QUOTE YOU RECEIVED MUCH LOWER THAN THE $3.91 YOU ARE ASKING THE COMMISSION TO ADOPT?

A. The price at Sumas is only part of the cost of getting the natural gas to load centers in Idaho. Ignoring those additional costs unfairly understates the cost of natural gas.

Q. PLEASE EXPLAIN?

A. It is sort of like renting a car. When you are quoted a price, say $50 a day, that is not the price you end up paying. After taxes, insurance, airport fees and surcharges you will pay more than the $50 you were quoted. Similarly there are many add-ons to the quoted price of natural gas.

Q. WHAT ARE THE ADDITIONAL CHARGES IN ADDITION TO THE COMMODITY CHARGE THAT YOU WOULD HAVE TO ADD TO THE $3.36 YOU WERE QUOTED?

A. First, you have a demand charge. Northwest Pipeline's demand charge is 27.76 cents per MMBtu and the commodity charge is 3 cents per MMBTu. Next you have what are called add-ons, which are collected by the pipeline on behalf of Gas Research Institute (the GRI charge) and the FERC (the ACA charge). The charge for ACA is .0021 per MMBtu and GRI is .0055 per MMBtu. This brings the total charges on Northwest Pipeline to 31.52 cents per MMBtu. Northwest also assesses a fuel-in-kind charge to cover compressor fuel and lost and unaccounted gas. Northwest's fuel charge is currently 1.7%, which for gas at $3.36 MMBtu would equal an additional charge of $.05712 per MMBtu. The fuel rate is adjusted as required by Northwest Pipeline and over the years it has ranged between 1% and 2%. Finally one has to add four to five cents, which is a producer firming charge. These charges add to an additional $0.41 to .$0.42 per MMBtu delivered to the city gate or the property boundary of a project if you are bypassing the local distribution company. Those are the costs, however, if you can get the natural gas delivered. Further, if one is only operating their plant 90% of the time you have effectively added almost three cents to your transportation charge making all of the additional charges in the $.44 to $.45 range.

Q. WHAT DO YOU MEAN, IF YOU CAN GET THE NATURAL GAS DELIVERED?

A. Currently all of the capacity on Northwest Pipeline into Southern Idaho from both Canadian and domestic sources is fully sold by Northwest Pipeline with the exception of 13,322 MMBtu/day which would require contract operational flow (CFO) order language. This small amount of firm transportation capacity is not sufficient to meet the needs of a large firm load such as a gas fired combustion turbine would require (approximately 40 million cubic feet a day is required for a 230 to 250 MW generator depending on elevation.)

Q. WHAT IS THE ISSUE WITH CAPACITY ON THE NORTHWEST PIPELINE?

A. There may be interruptible capacity available at times and one may or may not be able to locate released capacity. However it would not be prudent to build a large gas fired CT that has a capacity factor of 90 percent to rely on an interruptible transportation arrangement. In addition, released capacity may or may not be available. Certainly individual space holders such as large marketers may be willing to release for some period of time a portion of their firm capacity. Whether they would be willing to do so, and for fifteen to twenty years, is speculative. It may be there today and it may not be there tomorrow.

Q. WHAT IS THE SOLUTION TO THE LACK OF FIRM TRANSPORTATION CAPACITY ON THE PIPELINE?

A. The owner of the new CT would have to participate in what is called a pipeline expansion project. In analyzing and estimating future gas prices, the Northwest Power Planning Council study done under the direction of Terry Morlan, utilized $.12 per MMBtu as an additional firm transportation cost related to expansion. I think his estimate is a reasonable one (and perhaps a little low) for a Northwest Pipeline expansion project into Southern Idaho. Therefore, when you add up all of the charges and add ons which are itemized below, the natural gas price recommended by Mr. Trippel of $3.91 and the Pacific witness of $3.95 appear to be the only prices in this docket that reflect reality.

Quoted Gas Price	$3.36 per MMBtu
Demand Charge	$0.2776 per MMBtu
GRI Charge	$0.0055 per MMBtu
ACA Charge	$0.0022 per MMBtu
Fuel Charge	$0.05712 per MMBtu
Gas Firming Charge	$0.05 per MMBtu
Pipeline Expansion	$0.12 per MMBtu
Capacity Factor	$0.03 per MMBtu
Total Actual Price	$3.90242 per MMBtu

Q. WHICH PRICE DO YOU RECOMMEND THIS COMMISSION ADOPT FOR COMPUTING AVOIDED COST RATES?

A. I recommend the Commission adopt the price recommended by Mr. Trippel of $3.91. However, the Pacific price of $3.95 would also be reasonable.

Q. PULL OUT YOUR CRYSTAL BALL AND TELL US WHAT YOU PREDICT FOR THE FUTURE OF NATURAL GAS PRICES?

A. Prices are going to go up and down. By all accounts and national measures of the drilling production and deliverability and consumption of natural gas, natural gas has become a just-in-time commodity. This means that the amount of gas deliverable from the wellhead and storage is equivalent to the volumes required during high consumption winter and summer months. However in the near term, analysts believe we are in for another round of increases in prices for several reasons. The rig count in the U.S. and Canada is down sharply as is shown on my Exhibit 606. The economic downturn has decreased expected consumption by approximately, plus or minus one trillion cubic feet annually, over what was expected. While one might think this would buy us time to increase our drilling and deliverability, it has resulted in wellhead price decreases that have resulted in seismic and drilling declines. New supply is simply not being brought to market at the rate it was in the recent past. Increases in rig counts have a tendency to follow increases in prices and declining rig counts tend to foreshadow increases in prices. We appear to be reaching the bottom of this declining rig count cycle. Therefore it appears to be the consensus (See for example my Exhibit No. 607) that we are in for a period of increasing prices. This is reflected in cotango pricing displayed on the NYMEX futures chart.

One also has to understand that there is an alarming decrease in investment in the skills and infrastructure necessary to produce the gas we need in the future, as discussed in the article entitled "Regulators Warned of Supply, Manpower Crisis" which is attached as my Exhibit 607.

Q. YOU HAVE OFFERED EXHIBIT 607 THAT SPEAKS TO THESE ISSUES IN WHICH DR. CHARLES J. MANCON IS QUOTED, DO YOU KNOW HIM?

Yes, Dr. Mancon was director of the Okalahoma Geological Survey and Chairman of the Department of Geology and Geophysics at the University of Okalahoma when I received my Masters of Science in Geology. He was also a member of my thesis committee. He is a renowned geoscientist and geopolitical and natural resource analyst. He speaks to a lack of activity and manpower associated with meeting a national goal of thirty trillion cubic feet available for consumption.

Q. WHAT OTHER FACTORS SUGGEST THAT PRICES WILL BE INCREASING?

A. With the addition of new eastward bound take-away transportation capacity from Western Canada, California and the Northwest are no longer the black hole for Canadian energy. There is a greater transparency across the country with natural gas pricing today than there was ten years ago. While there is still a basis differential between Sumas and the Henry Hub, there are now months when Sumas trades at a positive basis to Henry. Ninety-five percent of all new electric generation across the United States is scheduled to be natural gas fired turbines. Their consumption, coupled with normal economic growth, will work to create periodic straining on the total natural gas system - wellhead to burner tip. Natural gas currently has the highest degree of volatility of any commodity traded. With the national financial issues associated with major market makers and traders, the futures market has become much more illiquid from two years forward than it was in the past. It appears there is less gas being traded for longer than a two-year period. Long-term credit is an issue for both the buyer and the seller and the third party providing the financial hedge. In the end, this out year uncertainty and price volatility probably adds costs to the buyer's side of the transaction.

In summary, do I believe we will see $6.00 to $7.00 per MMBTu gas prices in the future? The answer is yes. We will also see $2.50 per MMBtu and $3.50 per MMBtu prices. The price of gas will be cyclical. In twenty years, I believe, we will look back and see that the gas of price was cyclical with a general upward trend.

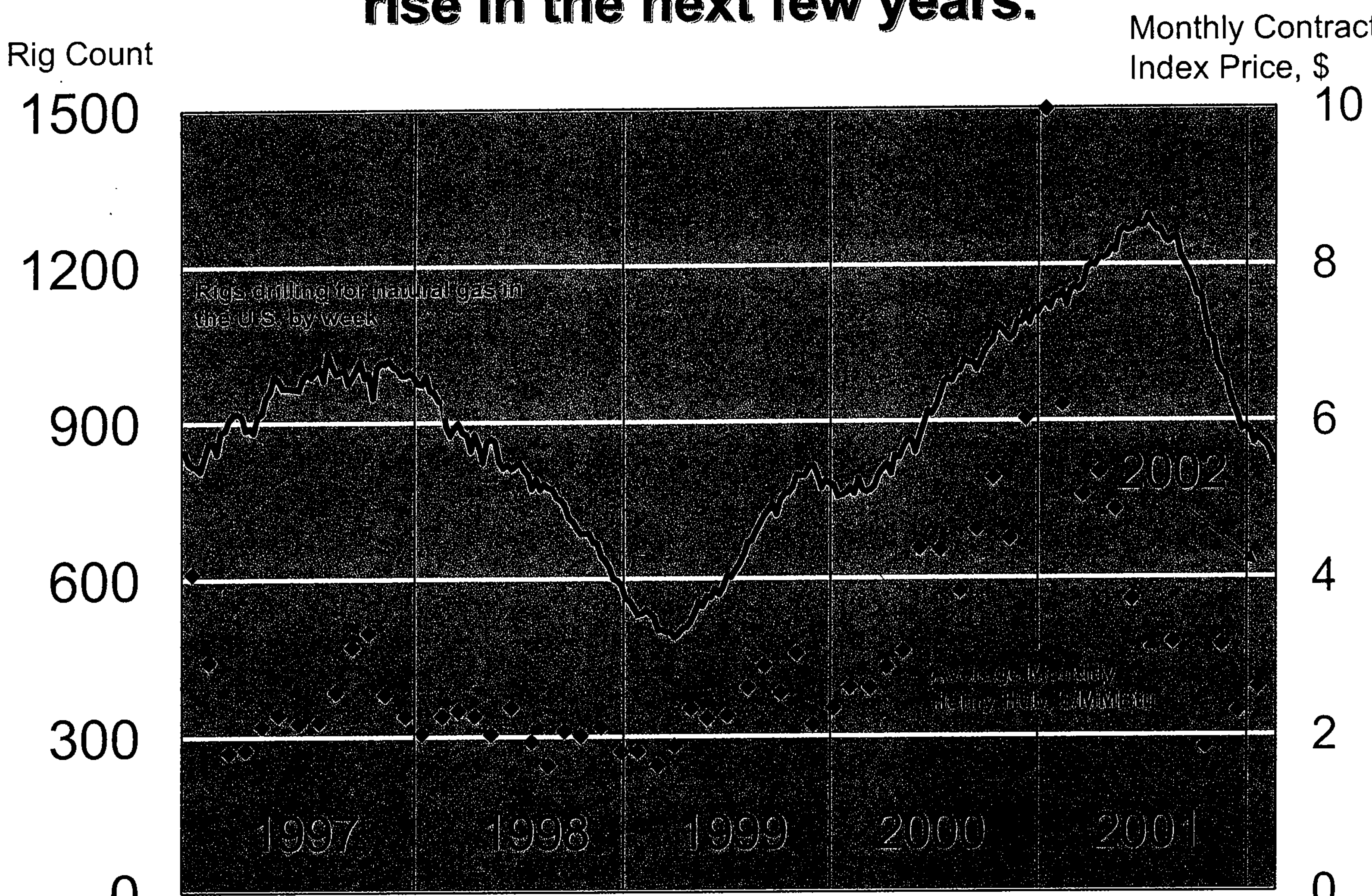
DOES THIS CONCLUDE YOUR TESTIMONY?

Yes. It does.

EXHIBIT NO. 606

RIG COUNT

Rig counts are dropping, indicating that the market is heading into a bust cycle. Gas prices may rise in the next few years.



Souce: Baker Hughes; Gas Daily. Prices not adjusted for inflation.

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David Hawk
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EXHIBIT NO. 607

PLATTS GAS DAILY

REGULATORS WARNED OF SUPPLY, MANPOWER CRISIS

platts

Gas Daily®

Wednesday, July 31, 2002

Daily Price Survey

Listed in the left column are the midpoints of the daily ranges for the most common prices, paid in $/mmBtu of a typical volume of 5 thousand mmBtu. The middle column shows absolute low-high prices for transactions reported on the date at the top of the column; the third column shows that day's ranges for the most common prices. The prices are generally for gas flowing today; weekends are usually priced using data collected Friday. Ranges are for deals done before nomination deadlines. The common range is built around the volume weighted average and the midpoint is calculated for the common range. Data in this table is Copyright 2002 by The McGraw-Hill Companies, Inc.

NATIONAL AVERAGE PRICE: $3.055****

Trans. date: 7/30

Flow date(s): 7/31

	Midpoint	Absolute	Common
Permian Basin Area			
El Paso, Permian Basin	2.740	2.71-80	2.72-76
Northern, MIDS 1-6	2.750	2.73-79	2.73-77
Waha	2.830	2.80-86	2.81-85
Transwestern, Permian Basin	2.740	2.73-75	2.73-75
East Texas-North Louisiana Area			
Carthage Hub	2.935	2.90-95	2.92-95
Lone Star	2.705	2.70-71	2.70-71
MRT, mainline	3.010	2.95-3.02	3.00-02
MRT, west leg	2.990	2.95-3.00	2.98-3.00
NGPL, Texok zone	2.925	2.90-95	2.91-94
Texas Eastern, ETX	2.980	2.92-3.02	2.96-3.02
Texas Gas, zone 1	2.950	2.90-3.02	2.92-98
East-Houston-Katy			
Houston Ship Channel	2.985	2.96-3.01	2.97-3.00
Katy	2.950	2.93-97	2.94-96
South-Corpus Christi			
Agua Dulce Hub	2.935	2.89-97	2.91-96
Houston Pipe Line	—	—	—
NGPL, STX	2.905	2.90-92	2.90-91
Tennessee, zone 0	2.915	2.89-95	2.88-95
Texas Eastern, STX	2.950	2.85-3.03	2.90-3.00
Transco, zone 1	2.650	2.60-72	2.62-68
Trunkline, Texas	—	—	—
EPGT, Texas	2.955	2.95-99	2.95-96
Louisiana-Onshore South			
ANR, La.	2.925	2.86-95	2.91-04
Columbia Gulf, La.	2.980	2.89-3.03	2.92-3.00
Columbia Gulf, mainline	3.040	3.00-09	3.02-06
Florida Gas, zone 1	3.025	3.00-05	3.01-04
Florida Gas, zone 2	3.080	3.00-12	3.06-12
Florida Gas, zone 3	3.160	2.90-3.21	3.11-21
Henry Hub	2.975	2.91-3.02	2.95-3.00
Gulf South, S. La./East Side	2.740	2.72-76	2.73-75
NGPL, La.	2.930	2.01-04	2.92-94
Southern Natural, La.	3.015	2.94-3.07	2.98-3.05
Tennessee, La., 500 Leg	2.950	2.87-3.00	2.92-98
Tennessee, La., 800 Leg	2.950	2.86-3.00	2.91-99
Texas Eastern, WLA	2.995	2.91-3.03	2.96-3.03
Texas Eastern, ELA	3.055	2.98-3.10	3.02-09
Texas Gas, zone SL	2.945	2.88-98	2.92-97
Transco, zone 2	3.060	2.92-3.13	3.01-11
Transco, zone 3	3.110	2.98-3.15	3.07-15
Trunkline, WLA	2.945	2.92-98	2.93-96
Trunkline, ELA	2.925	2.90-96	2.91-94
Oklahoma			
ANR, Okla.	2.820	2.80-83	2.81-83
NGPL, Midcontinent	2.765	2.73-79	2.75-78
Reliant, East	2.930	2.90-94	2.92-94
Reliant, West	2.850	2.82-86	2.84-86
Oneok, Okla.	2.820	2.80-83	2.81-83
Panhandle, Tx.-Okla.	2.760	2.70-83	2.72-78
Williams, Tx.-Okla.-Kan.	2.840	2.81-86	2.83-85
New Mexico-San Juan Basin			
El Paso, Bondad	1.970	1.85-2.16	1.89-2.05
El Paso, San Juan Basin	2.535	2.45-58	2.50-57
Rockies			
CIG, Rocky Mountains	1.530	1.49-57	1.49-57
Kern River, Opal plant	1.610	1.51-79	1.54-66
Stanfield, Ore.	1.820	1.78-85	1.80-84
Questar, Rocky Mountains	1.505	1.42-60	1.48-55

continued on next page

Dismal earnings aside, Dynegy CEO sees hope

Dynegy's stock continued its rebound Tuesday even after the beleaguered energy trading company reported second-quarter financial results that were dramatically worse than a year ago. Dynegy's shares rose 45% to close Tuesday at $1.74.

Dynegy reported a $328 million second-quarter net loss after charges, compared with a year-earlier $146 million profit. Revenues were $9 billion, down from $10.8 billion in last year's second quarter.

In a conference call with analysts, Dynegy officials said the quarterly results include previously disclosed, pretax and nonrecurring charges of $499 million, or $324 million after-tax, and a recurring loss of $4 million. The company's total after-tax nonrecurring charges for the second quarter include $212 million for certain communications assets and technology investments, $80 million related to its gas marketing business and $32 million for employee severance and related exit costs and other write-offs.

Dynegy interim CEO Dan Dienstbier said the decline in commodity prices quarter-over-quarter and lower liquidity levels in the energy trading business substantially hurt the company. Dynegy's wholesale energy trading unit posted net income of just

(continued on page 5)

Regulators warned of supply, manpower crisis

A declining work force in the gas producing industry, increasing domestic demand and reduced imports from Canada over the next five to 10 years will lead to sustained wellhead prices above $4/Mcf in constant 2002 dollars, a consultant told the gas committee of the National Association of Regulatory Utility Commissioners on Tuesday.

Henry Groppe, a partner at Groppe, Long & Little in Houston, said imports of Canadian gas likely will peak this year at about 10 Bcf/day and drop to 6 Bcf/day in 2010 because of declining production in western Canada. That number takes into consideration increases from Nova Scotia and other frontier areas, he said.

In the United States gas production is declining in most areas, and with increasing demand for gas, "we see a totally new era" of higher prices that will restrain consumption and lead to more fuel-switching among large consumers, including power generators, Groppe told the NARUC conference in Portland, Ore. Relying so heavily on gas to meet peak power generation needs will "prove to be a mistake in time," Groppe predicted.

Charles Mankin, director of the Oklahoma Geological Survey and the Sharkey Energy Center at the University of Oklahoma, commented that increased imports of liq-

(continued on page 6)

New York cash hits $10; Western prices fall

The Market

New York cash prices soared again Tuesday — this time to $10 — as a combination of above-normal temperatures and pipeline restrictions continued to plague the region. Meanwhile, plentiful supply and slack demand in the West sent Malin, Ore., prices down 30¢ from Monday's average.

Prices on Transcontinental Gas Pipe Line Zone 6-New York shot higher for a variety of reasons, sources said, but mainly because of heat indices that hovered around 105 degrees in the Big Apple. Temperatures are expected to climb into mid-90s again today before a cooldown Thursday, sources said.

Intraday deals were reported around $8 by late morning, one source said, though next-day cash was more fickle. Early prices in the $4.70s soon gave way to $5, then $6 and $7 as the market began to overheat. But late in trading, deals were reported as high as $10 and offers were seen around $20, sources said.

Another trader said Tuesday was the busiest and most volatile trading day of the year so far. "Usually, the winter months are the most volatile in the New York market, but I never saw a winter day as volatile as what we went through for the

EXHIBIT NO. 607
David Hawk
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Mirant reports $151 million loss; 2001 accounting errors possible

Citing new market uncertainties, Mirant on Tuesday announced a "second phase" of belt-tightening measures, including the sale later this year of its 49% holding in U.K. electric company Western Power Distribution.

Mirant said it hopes to raise between $700 million and $1 billion from asset sales including WPD and also will cut back capital investment by about $260 million in 2003, especially on new plant construction overseas.

The Atlanta-based company released its second-quarter financial results, which included a $284 million write-off of its WPD holding and a $18 million restructuring charge for recent staff cuts. The charges more than offset Mirant's $145 million in earnings from operations — now called adjusted earnings — leaving it with a net loss of $151 million for the quarter. That compares with an adjusted income of $181 million and a net income of $124 million in the same period last year.

At the same time, Mirant said its core domestic generation and marketing business had done surprising well in the quarter given the overall problems with the market. It contributed $121 million to earnings in the quarter, down only 24% from last year.

Mirant said it traded gas volumes of 22.3 Bcf/day during the quarter, up 89% over the year-earlier period, and sold 91.8 million MWh of electricity, up 32%.

Mirant President and CEO Marce Fuller said the results were helped by Mirant's large asset base, which is mainly located near major demand centers.

Also Tuesday, Mirant said it was reviewing $250 million in possible accounting errors in its 2001 financial results, but has no plans now to restate last year's earnings.

Fuller told analysts that an initial internal review showed the problems appeared to be "honest mistakes," involving the timing of when liabilities and gains were recorded. She said all amounts involved were "bona fide revenues."

Fuller said the problems were revealed during an internal reconciliation between accounts of the parent company and its Mirant Americas' unit. They included an $85 million overstatement of a gas asset, a $100 million overstatement of an accounts payable liability and a $68 million overstatement of an accounts receivable asset.

At the same time, she said that because of the heightened investor concerns about such issues, Mirant had retained an outside law firm to conduct an independent review of the potential errors while Mirant works to reconcile the accounts.

Fuller said Mirant does not plan to restate 2001 earnings unless it cannot satisfactorily reconcile the differences. She also said the company does not believe the problem will affect its 2002 results.

Fuller said that "integrity is and always would be the hallmark of Mirant's code of conduct" and she would do all possible to maintain accurate reporting and investor confidence. Mirant used Authur Anderson as its accounting firm until May, when it switched to KPMG.

status of receivables as well as unforeseen events," he said. "When this transaction closes, our liquidity will be very solid. It should put the liquidity question to rest, at least for the immediate future."

In addition to the Northern Natural sale, Dynegy hopes to improve its liquidity through the sales of its U.K. gas storage holdings, the offering of a bond for its Illinois Power assets and the creation of a master limited partnership for a portion of its liquids business. Dynegy has also said it hopes to find a joint venture partner for its energy trading business.

Analysts said Dynegy's second-quarter earnings report contained no surprises.

"Overall, it was pretty much what we had expected in concert with where Dynegy had guided," said Anatol Feygin, an analyst with J.P. Morgan. He said, however, that he expected Dynegy to shop Northern Natural around harder in an effort to get a better price. "I was surprised to hear that it was substantially a done deal. The company made it sound like there wasn't much of an opportunity for a counteroffer on the table," he said.

Several analysts worried that Dynegy would be caught in a Catch-22 — forced to sell off valuable assets to raise cash, it won't be able to use those assets to create long-term income and stability.

"What the new model looks like it's too early to tell. On the merchant energy side, Dynegy is quick to put out that you can't conduct that business without a strong investment-grade rating," Feygin said. "But they don't plan to be investment grade before year-end '03 and they don't even say strong investment grade. It's kind of obvious Dynegy doesn't see the Dynegy of 12 to 18 months from now as a strong merchant player." JM

Supply, manpower crisis seen ... *(from page 1)*

uefied natural gas can make "a major contribution" to meeting future demand.

Also, increasing access to areas that are currently off limits to producers, as was suggested Monday by an American Gas Association official (*GD 7/30*), will help, "but it is by no means a panacea," Mankin said.

Jim Renfroe, senior vice president of development for Halliburton, said producers and the service companies associated with the industry are facing a diminishing work force whose average age is 48. The sector expects to lose 60% of current staff by 2007, he said.

What's worse, young people are not pursuing geology or petroleum engineering degrees and most of those who are will go to work overseas after being trained in the United States, Renfroe added. In order to retain staff that has experience, companies will need to offer flexible work hours and part-time mentoring programs and increase recruiting outside the United States, Renfroe suggested.

Shoring up the work force in the producing and service sectors should become a significant priority, including efforts by universities and major gas and oil companies, Mankin said. Meeting projections for increased demand, such as a 30-Tcf annual U.S. market, will require "a national effort of epic proportions," Mankin said.

Groppe also noted that Wall Street is focused on short-term gains even though investments in gas and oil production take a long time to produce results — and that could make it harder for companies to raise capital.

Joshua Twilley of the Delaware Public Service Commission agreed that the speakers were presenting a scenario of "an approaching major crisis" in the supply sector. But he said "nobody's raising a red flag" about the problem in Washington or elsewhere to make sure officials are aware of the issues.

Similarly, Gary Feland, chairman of the Montana Public Service Commission, said the presentations showed that "we don't have the people needed, we don't have the money needed" and "we've got to have access to new areas," in order to stave off a troubling scenario. TT

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David Hawk
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